BART Determination 12/1/09
For
Coal Creek Station Units 1 and 2

I. Source Description

A. Owner/Operator: Great River Energy (GRE)

B. Source Type: Fossil-fuel fired steam electric plant of more than 250 million British thermal units (Btu) per hour heat input and having a total generating capacity in excess of 750 megawatts.

C. BART Eligible Units

1. EU 1 - Unit 1 boiler

2. EU 2 - Unit 2 boiler

3. EU 3 - Auxiliary boiler No. 91

4. EU 4 - Auxiliary boiler No. 92

5. EU 5 - Emergency generator

6. EU 6 - Fire pump engine

7. EU 7 through EU 26 material handling units, including coal and lime handling operations and flyash silos

a. EU 7 - Lignite transfer house

b. EU 8 - Lignite emergency reclaim system

c. EU 9 - Lignite yard storage silos

d. EU 10 - Lignite yard storage silos

e. EU 11 - Crusher building (Two 1,500 ton per hour crushers)

f. EU 12 - Generation building coal hopper

g. EU 13 - Falkirk Mining Company mine silo base

h. EU 14 - Generation building coal hopper

i. EU 15 - Generation building coal hopper

j. EU 16 - Generation building coal hopper

k. EU 17 - Generation building coal hopper

l. EU 19 - Scrubber building flyash silo

m. EU 20 - Truck air slide flyash silo

n. EU 21 - Truck air slide flyash silo

o. EU 22 - Water treatment building

p. EU 23 - Scrubber building lime handling system

q. EU 24 - Scrubber building lime handling system

r. EU 25 - Flyash railroad marketing silo

s. EU 26 - Flyash dome

8. FS 1 through FS 5 - Fugitive sources

a. FS 1 - Cooling Towers No. 91, No. 92, and No. 93

b. FS 2 - Boombelt conveyor (stackout)

c. FS 3 - Conveyor 909 (stackout)

d. FS 4 - Scrubber building flyash silo (stackout)

e. FS 5 - Coal pile maintenance

D. Unit Description

1. EU 1 - Unit 1 boiler:

Generator Nameplate Capacity: 550 MWe

Boiler Rating: 6,015 x 10^6 Btu/hour

Startup: 1979

Fuel: North Dakota lignite

Firing Method: Tangential-fired pulverized coal (PC) unit

Existing Air Pollution Equipment:

Electrostatic precipitator (ESP)
Low NO_x burners (LNB) and separated over fire air (SOFA)
Wet scrubber

2. EU 2 - Unit 2 boiler

Generator Nameplate Capacity: 550 MWe

Boiler Rating: 6,022 x 10^6 Btu/hour

Startup: 1980

Fuel: North Dakota lignite

Firing method: Tangential-fired pulverized coal (PC) unit

Existing Air Pollution Equipment:

Electrostatic precipitator (ESP)
Low NO_x burners (LNB) and separated over fire air (SOFA)
Wet scrubber

3. EU 3 - Auxiliary boiler No. 91

Boiler rating: 172 x 10^6 Btu/hour

Fuel: Residual oil, distillate fuel oils, or any combination of these fuels

Existing air pollution equipment: None

4. EU 4 - Auxiliary boiler No. 92

Boiler rating: 172 x 10^6 Btu/hour

Fuel: Residual oil, distillate fuel oils, or any combination of these fuels

Existing air pollution equipment: None

5. EU 5 - Emergency generator

Rating: 3,500 bhp

Fuel: No. 2 fuel oil or a blend of No. 1 and No. 2 fuel oil

Existing air pollution equipment: None

6. EU 6 - Fire pump engine

Rating: 200 bhp

Fuel: No. 2 fuel oil or a blend of No. 1 and No. 2 fuel oil

Existing air pollution equipment: None

7. EU 7 through EU 26 - Material handling units, including lime handling operations and flyash silos

Existing air pollution equipment: Fabric filters/bag houses

8. FS 1 through FS 5 - Fugitive sources

Existing air pollution equipment: None - fugitive emissions

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 1 - Unit 1 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu)	14,332 0.56	14,630 0.56	11,910 0.51	13,817 0.54	15,742 0.61	14,086 0.56
	NO_x (tons) NO_x (lb/10^6 Btu)	5,211 0.21	5,235 0.21	4,690 0.21	5,072 0.20	5,370 0.21	5,116 0.21
	PM (tons) PM (lb/10^6 Btu)	632 0.025	492 0.019	1,305 0.056	73 0.003	116 0.005	524 0.021

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 2 - Unit 2 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu) NO_x (tons) NO_x (lb/10^6 Btu) PM (tons) PM (lb/10^6 Btu)	12,817 0.53 5,324 0.22 827 0.034	11,683 0.51 5,190 0.23 649 0.028	12,518 0.49 5,454 0.22 1,268 0.050	13,547 0.54 5,558 0.22 121 0.005	11,469 0.50 5,429 0.24 80 0.003	12,407 0.51 5,391 0.23 589 0.024
EU 3 - Auxiliary boiler No. 91	PM (tons) SO_2 (tons) NO_x (tons)	0.10 0.30 0.10	0.00 0.00 0.10	0.10 0.00 0.10	0.00 0.00 0.00	0.00 0.00 0.10	0.02 0.06 0.10
EU 4 - Auxiliary boiler No. 92	PM (tons) SO_2 (tons) NO_x (tons)	0.10 0.30 0.10	0.60 1.30 0.40	0.00 0.00 0.00	0.00 0.00 0.00	0.00 0.00 0.00	0.14 0.32 0.10
EU 5 - Emergency generator	SO_2 (tons) NO_x (tons)	0.45 2.76	0.04 3.07	0.04 2.76	0.04 2.69	0.97 3.06	0.31 2.87
EU 6 - Fire pump engine	SO_2 (tons) NO_x (tons)	0.01 0.09	0.01 0.10	0.01 0.11	0.01 0.11	0.01 0.12	0.01 0.11
EU 7 - Lignite transfer house	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 8 - Lignite emergency reclaim system	PM (tons)	0.00	0.00	0.00	0.00	0.00	0.00
EU 9 - Lignite yard storage silos	PM (tons)	0.03	0.03	0.03	0.03	0.03	0.03
EU 10 - Lignite yard storage silos	PM (tons)	0.03	0.03	0.03	0.03	0.03	0.03
EU 11 - Crusher building	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 12 - Generation building coal hopper	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 13 - Falkirk mining Company mine silo base	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07

BART Eligible Unit	Pollutant	2000	2001	2002	2003	2004	2000-2004 Ave.
EU 14 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 15 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 16 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 17 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 19 - Scrubber building flyash silo	PM (tons)	0.01	0.02	0.02	0.03	0.03	0.02
EU 20 - Truck air slide flyash silo	PM (tons)	0.05	0.04	0.04	0.04	0.07	0.05
EU 21 Truck air slide flyash silo	PM (tons)	0.05	0.04	0.04	0.04	0.06	0.05
EU 22 - Water treatment building	PM (tons)	0.05	0.04	0.04	0.02	0.00	0.03
EU 23 - Scrubber building lime handling system	PM (tons)	0.03	0.03	0.02	0.02	0.01	0.02
EU 24 - Scrubber building lime handling system	PM (tons)	0.03	0.03	0.02	0.02	0.01	0.02
EU 25 - Flyash railroad marketing silo	PM (tons)	0.03	0.03	0.02	0.02	0.14	0.05
EU 26 - Flyash dome	PM (tons)	0.00	0.00	0.00	0.00	0.11	0.02
FS 1 - Cooling towers No. 91, No. 92 & No. 93	PM (tons)	0.02	0.02	0.01	0.02	0.02	0.02
FS 2 - Boombelt conveyor (stackout)	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
FS 3 - Conveyor 909 (stackout)	PM (tons)	0.02	0.03	0.04	0.05	0.05	0.04
FS 4 - Scrubber building flyash silo (stackout)	PM (tons)	0.02	0.03	0.04	0.05	0.05	0.04

BART Eligible Unit	Pollutant	2000	2001	2002	2003	2004	2000-2004 Ave.
FS 5 - Coal pile maintenance	PM (tons)	3.77	3.77	3.77	3.77	3.77	3.77

II. Site Characteristics

The Coal Creek Station is a two-unit, 1,100 gross megawatt (MW) mine-to-mouth power plant consisting primarily of two steam generators and associated coal and ash handling systems. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially from a maximum of 64 firing points each. Unit 1 has a heat input capacity of 6,015 x 10^6 Btu/hr; Unit 2 is rated at 6,022 x 10^6 Btu/hr. Particulate matter from each boiler is controlled by a 99.5% efficient electrostatic precipitator (ESP) consisting of 48 transformer rectifier (TR) sets. A four-module flue gas desulfurization (FGD) system for each boiler removes approximately 90% of the sulfur dioxide from 60% of the flue gas. Each boiler is served by a 655 foot high stack.

Unit 1 began commercial operation in 1979 and Unit 2 in 1980. The facility is located in south central McLean County about five miles south of the town of Underwood, North Dakota and three miles west of US Highway 83. Coal Creek Station receives its lignite from the Falkirk Mine that is operated by the Falkirk Mining Company, a subsidiary of the North American Coal Corporation. Approximately 8,130,000 tons of lignite coal and approximately 165,000 gallons of oil were combusted in 2006.

III. BART Evaluation of Unit 1 and Unit 2

The BART guidelines apply to Units 1 and 2 because they are part of a fossil-fuel steam electric plant with a total generating capacity in excess of 750 megawatts, they are rated at more than 250 million Btu per hour heat input, and they have potential emissions of 250 tons or more per year of a visibility-impairing pollutant, specifically SO_2, NO_x and PM_{10}.

Since Units 1 and 2 are identical, the following evaluation will use values derived by averaging the historical data for each unit and then make a single BART determination that will be applicable to each unit.

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Coal Cleaning/Washing
K-Fuel®
TurboSorp®
Coal Drying
Dry Sorbent Injection
Spray Dryer

Wet Scrubber Modification
Wet Scrubber Replacement

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning/Washing: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that have required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Center Mine was tested. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® and will be submitted to this Department at the end of the approved burn period process available or technically and economically feasible.

TurboSorp®: Although the GRE analysis concluded otherwise, the Department considers TurboSorp® dry flue gas desulfurization technology to be technically feasible because it employs the proven technology of circulating dry scrubbers. Additional information on this technology is found at:
http://www.eucetsa.net/eucetsa/webPages.do?pageID=200913.

Coal Drying: Coal drying of lignite has been demonstrated to be technically feasible through pilot projects at this facility. Furthermore, dried lignite is the primary fuel for another ND facility, the GRE Spiritwood Station, that received a permit to construct September 14, 2007.

In addition to coal drying, the remaining control technologies, dry sorbent injection, spray dryer, and wet scrubber (modification or replacement), are considered to be technically feasible. GRE has elected to install coal drying equipment independent of the SO_2 control chosen.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Baseline SO_2 Emissions Controlled (past): Based on average actual controlled annual emissions when combusting lignite (undried) for a 24 month period (2003-2004) with 27% bypass: (13,817 [Unit 1, 2003] + 13,547 [Unit 2, 2003] + 15,742 [Unit 1, 2004] + 11,469 [Unit 2, 2004])/4 = 13,644 ton/yr average baseline controlled SO_2 emissions with 27% bypass and undried coal.

Applying the 68% overall control efficiency of the existing scrubber yields: [(13,644 ton/yr)/(1-0.68)] = 42,638 ton/yr uncontrolled baseline SO_2 emissions.

The 42,638 ton/yr uncontrolled baseline SO_2 emissions are based on past undried coal with an average 2003-2004 sulfur content of 0.61%. The evaluation of alternative SO_2 cleaning equipment will be based on future undried coal with an expected worst case (98 percentile) sulfur content of 1.10%, as predicted for Falkirk coal and provided by GRE. Therefore, the uncontrolled baseline SO_2 emissions above must be adjusted to the future sulfur content so that an apples to apples comparison will correctly determine emission reductions expected to result from employing the alternative equipment. The 42,638 ton/yr uncontrolled baseline SO_2 emissions is adjusted as follows: (42,638 ton/yr)(1.1%/0.61%) = 76,888 ton/yr uncontrolled baseline SO_2 emissions for undried coal with future sulfur content.

For the purposes of this analysis, the adjustment to future coal was considered necessary only for SO_2 and the related condensible particulate matter and sulfuric acid mist emissions due to the increased sulfur content expected in future coal. For all other pollutants, this analysis does not adust to future coal due to the negligible impact on emissions. No adjustment to the baseline was made for coal drying because the Permit to Construct is not expected to require dried lignite or limit moisture content.

Note: TurboSorp® is a registered trademark for Babcock Power Environmental's circulating dry scrubber. The Department considers circulating dry scrubbers to be technically feasible. Circulating dry scrubbers will generally achieve SO_2 removal efficiencies similar to spray dryer absorbers but less than wet scrubbers. Other BART analyses projected a removal efficiency of 93% with higher costs than a new wet scrubber. Since a circulating dry scrubber will have a lower removal efficiency than a wet scrubber or upgrades to the existing wet scrubber (95% and 94%, respectively) and will cost more than a new wet scrubber or upgrades to the existing wet scrubber, a circulating dry scrubber is an inferior option and is not considered further.

Future Case

Alternative	Control Efficiency (%)	Baseline Uncontrolled Emissions (tons/yr)*	Controlled Emissions*	
			(tons/yr)	(lb/10^6 Btu)**
Wet Scrubber Replacement***	95	76,888	3,844	0.146
Wet Scrubber Modification***	95	76,888	3,844	0.146
Spray Dryer***	90	76,888	7,689	0.292
Existing Scrubber & 0% Bypass	83.1	76,888	12,994	0.493
Dry Sorbent Injection***	70	76,888	23,066	0.875
Existing Scrubber & 27% Bypass	68****	76,888	24,604*****	--

* Future lignite at 1.10% (GRE-predicted worst-case sulfur content for Falkirk Mine lignite. As a result, Department baseline future emission estimates are somewhat higher than GRE's estimates)

** Annual

*** 0% bypass

**** Current control rate

***** Current controlled emissions = 76,888(1-0.68) = 24,604 tpy

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on the past emissions adjusted for the sulfur content of future coal, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness($/ton)	Incremental Cost ($/ton)
Wet Scrubber Replacement	20,760	30,760,000	1,482	24,987
Wet Scrubber Modification	20,760	11,520,000	555	--
Spray Dryer**	16,915	29,220,000	1,727	--
Existing Scrubber 0% Bypass	11,610	9,840,000	848	N/A
Dry Sorbent Injection**	1,538	12,520,000	8,140	N/A

* Costs provided by GRE

** Inferior option to wet scrubber modifications

N/A Not applicable since the cost effectiveness of the less efficient alternative is more than the more efficient alternative

The incremental cost associated with wet scrubber replacement ($24,987/ton) as compared to wet scrubber modification represents an excessively high cost relative to the emission reduction obtained.

Energy and Non-air Quality Effects: GRE has evaluated the energy and non-air quality effects of each option. Although the Department has determined that the information presented by GRE concerning these effects does not appear to preclude the selection of any of the five alternatives above, the possible economic impacts due to extensive process downtime associated with scrubber replacement and dry sorbent injection may be significant negative factors for their selection.

Step 5: Evaluate Visibility Results

The three primary alternatives and associated removal efficiencies are a wet scrubber replacement (95%), wet scrubber modification (95%) and spray dryer (90%). GRE estimated the effects on visibility due to SO_2 reductions (GRE BART Analysis, pages 47-51). Although these estimates were based on 94% SO_2 control for the wet scrubber modification, GRE subsequently agreed to 95% control for that option.

Step 6: Select BART

While the cost effectiveness is reasonable for all technologies evaluated except dry sorbent injection, the incremental cost associated with wet scrubber replacement is excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The units have existing wet scrubbers for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. With identical levels of SO_2 control, wet scrubber replacement involves additional cost with no improvement in visibility at any Class I area when compared to wet scrubber modification.

The Department proposes that BART is scrubbing 100% of the flue gas stream, the use of wet scrubber modifications to achieve a minimum control efficiency of 95% (30-day rolling average) on the inlet sulfur dioxide concentration to the scrubber or 0.15 lb/10^6 Btu (30-day rolling average). Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

Multiclone
Replacement Dry Electrostatic Precipitator (ESP)
Polishing Wet ESP
Baghouse

Step 2: Eliminate Technically Infeasible Options

The multiclone is considered technically infeasible because it has not been successfully demonstrated at a similar plant. All remaining technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	**Control Efficiency**	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)***
Replacement Dry ESP	99.75	388	0.015
Polishing Wet ESP	99.75	388	0.015
Baghouse	99.75	388	0.015
Baseline (Existing ESP)	99.50	775	0.030

* Based on potential-to-emit (see page 15-16 of GRE's analysis).

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on historic baseline emissions, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction* (tpy)**	**Annualized Cost** ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost*** ($/ton)**
Replacement Dry ESP	387	10,060,000	25,995	N/A
Polishing Wet ESP	387	1,920,000	4,961	N/A
Baghouse	387	7,670,000	19,819	N/A
Baseline (Existing ESP)	0	0	---	---

* Reductions from the baseline emission rate
** Costs provided by GRE
*** As compared to the baseline
N/A Not applicable since the all alternatives are equally efficient

Energy and Non-air Quality Effects: GRE has evaluated the energy and non-air quality effects of each option. The Department has determined that the information presented by GRE concerning these effects does not appear to preclude the selection of any of the alternatives above.

Step 5: Evaluate Visibility Impacts

The reduction in PM_{10} emissions that could be expected to be realized by implementing any of the three alternatives would produce a visibility improvement of less than 0.027 Δ-dV (98th percentile), a negligible improvement for the additional cost required.

Energy and Non-air Quality Effects: There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options.

Step 6: Select BART

The units have an existing dry ESP for removing filterable particulate matter and the plant is expected to have a remaining useful life of at least 20 years. Pre-BART modeling showed that PM from Units 1 and 2 contribute negligibly to visibility impairment as compared to sulfates and nitrates. The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the polishing wet ESP. This system has a cost effectiveness of $4,961 per ton of particulate when compared to the current emission control system (ESP operating at 99.5% efficiency). Considering the negligible improvement in visibility that would be achieved by adding a polishing wet ESP, the Department considers this cost, as well as the costs of the more expensive options, to be excessive.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Current actual emissions are less than the current allowable emissions, and combusting dried lignite can be expected to further reduce particulate emissions. Based on past actual emissions and allowing for an additional margin of safety to provide a reasonable possibility for compliance, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by the use of wet scrubber modifications to achieve a minimum SO_2 control efficiency of 95% and 100% of the flue gas stream. These changes are expected to reduce sulfuric acid mist emissions by approximately 90%. Changes that would provide additional reductions are economically infeasible considering the minimal improvement in visibility that could be achieved.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

Both GRE and AP-42, Compilation of Air Pollutant Emission Factors[2], indicate the emission rate of condensible particulate matter could be expected to be 0.02 lb/10^6 Btu. This emission rate is less than the current emissions of filterable particulate matter and the emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

External Flue Gas Recirculation
Selective Catalytic Reduction (SCR) High Dust
Electro-Catalytic Oxidation
Pahlman Process
SCR Low Dust
Low Temperature Oxidation (LTO), either Tri-No_x® or LoTOx
Selective Non-Catalytic Reduction (SNCR), No_xOut®
Modified and Additional Separated Overfire Air (SOFA)
Low NO_x Burners (LNB)

Step 2: Eliminate Technically Infeasible Options

Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE. The Department believes that low dust or tail end SCR has a good probability of successful application at Coal Creek and high dust SCR is technically infeasible (see discussion in Appendix B.5).

External Flue Gas Recirculation is technically infeasible due to limited space for ductwork and reduced flame temperature.

Electro-Catalytic Oxidation and the Pahlman Process considered technically infeasible because they are still in development and testing and have not been demonstrated to be commercially available. The remaining technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department’s estimated emissions using the various technologies are as follows:

Alternative	Control* Efficiency (%)	Controlled Emissions**	
		(tons/yr)	lb/10^6 Btu)
LTO	90	536	0.022
SCR Low Dust	80	1,071	0.043
SNCR	50	2,679	0.108
SOFA/LNB Opt 1	30	3,750	0.15
SOFA/LNB Opt 2	21	4,232	0.17
Baseline	0	5,357	0.22

* Control efficiency provided in GRE's analysis.
** Calculated from the historic baseline (2003-2004). The emission rate is an annual average rate.

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on historic baseline emissions, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
LTO	4,821	58,070,000	12,045	3,589*
SCR Low Dust	4,286	56,150,000	13,101	20,678**
SNCR	2,678	22,900,000	8,551	20,766***
SOFA/LNB Opt 1	1,607	660,000	411	664****
SOFA/LNB Opt 2	1,125	340,000	302	---

* LTO compared to SCR Low Dust
** SCR Low Dust compared to SNCR
*** SNCR compared to SOFA/LNB Opt 1
**** SOFA/LNB Opt 1 compared to SOFA/LNB Opt 2

Note: SCR and SNCR estimates above include the costs associated with lost ash sales and increased landfilling requirements due to ammonia slip rendering the ash ineligible for beneficial use. Although they were included in the GRE analysis and the table above, if the sunk costs for the ash sales infrastructure are appropriately disregarded, then the annualized cost for SNCR would be $21,750,000, the cost effectiveness would be $8,122 per ton, and the incremental cost would be $19,692 per ton.

NDDAQ was unable to determine that SNCR and its associated use of ammonia will not negatively impact GRE's ash sales; in fact, there is evidence to the contrary. GRE emails dated 8/8/08 and 8/17/08 provide additional information on this issue, as does a summary of a University of Kentucky study on the matter. Furthermore, in a BART and PSD analysis for the Omaha Public Power District Nebraska City Station Unit #1 coal boiler (Construction Permit Number CP07-0049, 2/26/09 fact sheet, pg. 14), Nebraska DEQ determined SCR was not BART in part because . . ."ammonia used in the system would cause the ash to be contaminated, thereby jeopardizing the current beneficial reuse of a portion of the ash produced by NCS Unit 1."

After considering all the information available, NDDH reached the following conclusions.

- SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
- The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
- The maximum level of ammonia in fly ash that would still avoid negative impacts on the salability of the ash cannot be predicted. Levels as low as 100 ppm have made the fly ash unfit for use in concrete.[4]

The NDDH believes there is reasonable possibility that SCR or SNCR will result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Lost ash sales will inflict a significant financial penalty on GRE and send ash to a landfill instead of it being used beneficially. If this ash is regulated as a hazardous waste, the financial burden will be even greater.

Energy and environmental impacts associated with the alternatives being considered include additional energy consumption (LTO, SCR), additional wastewater (LTO), ammonia slip (SCR, SNCR), potential to require ash to be landfilled (SNCR). The Department encourages the beneficial use of fly ash for making concrete. Ammonia slip associated with SNCR and SCR would preclude this beneficial use.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of LTO, SCR Low Dust and SNCR to be excessive. GRE estimated the effects on visibility due to NO_x reductions (GRE BART Analysis, pages 47-51).

The following tables show the visibility impacts of the SOFA/LNB Options 1 and 2, and SNCR.

Coal Creek Station Unit 1 or 2 Delta Deciview 90th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SNCR 50% Reduction	Difference
2000	TRNP-SU	0.119	0.106	0.013
2001	TRNP-SU	0.108	0.096	0.012
2002	TRNP-SU	0.207	0.186	0.021
Average	TRNP-SU	0.145	0.129	0.015
2000	TRNP-NU	0.118	0.105	0.013
2001	TRNP-NU	0.136	0.127	0.009
2002	TRNP-NU	0.151	0.131	0.020
Average	TRNP-NU	0.135	0.121	0.014
2000	Elkhorn Ranch	0.082	0.072	0.010
2001	Elkhorn Ranch	0.076	0.069	0.007
2002	Elkhorn Ranch	0.129	0.118	0.011
Average	Elkhorn Ranch	0.096	0.086	0.009
2000	Lostwood W.A.	0.207	0.180	0.027
2001	Lostwood W.A.	0.207	0.180	0.027
2002	Lostwood W.A.	0.165	0.141	0.024
Average	Lostwood W.A.	0.193	0.167	0.026
Overall Average		0.142	0.126	0.016

Coal Creek Station Unit 1 or 2 Delta Deciview 98th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SNCR 50% Reduction	Difference
2000	TRNP-SU	0.467	0.410	0.057
2001	TRNP-SU	0.482	0.437	0.045
2002	TRNP-SU	1.140	1.052	0.088
Average	TRNP-SU	0.696	0.633	0.063
2000	TRNP-NU	0.416	0.352	0.064
2001	TRNP-NU	0.512	0.436	0.076
2002	TRNP-NU	0.918	0.813	0.105
Average	TRNP-NU	0.615	0.534	0.082
2000	Elkhorn Ranch	0.300	0.270	0.030
2001	Elkhorn Ranch	0.473	0.405	0.068
2002	Elkhorn Ranch	0.746	0.654	0.092
Average	Elkhorn Ranch	0.506	0.443	0.063
2000	Lostwood W.A.	0.469	0.417	0.052
2001	Lostwood W.A.	0.469	0.417	0.052
2002	Lostwood W.A.	0.783	0.680	0.103
Average	Lostwood W.A.	0.574	0.505	0.069
Overall Average		0.598	0.529	0.069

Coal Creek Station Unit 1 or 2 Delta Deciview 90th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SOFA/LNB Option 2 21% Reduction	Difference
2000	TRNP-SU	0.119	0.125	0.006
2001	TRNP-SU	0.108	0.116	0.008
2002	TRNP-SU	0.207	0.219	0.012
Average	TRNP-SU	0.145	0.153	0.009
2000	TRNP-NU	0.118	0.124	0.006
2001	TRNP-NU	0.136	0.142	0.006
2002	TRNP-NU	0.151	0.158	0.007
Average	TRNP-NU	0.135	0.141	0.006
2000	Elkhorn Ranch	0.082	0.088	0.006
2001	Elkhorn Ranch	0.076	0.076	0.000
2002	Elkhorn Ranch	0.129	0.136	0.007
Average	Elkhorn Ranch	0.096	0.100	0.004
2000	Lostwood W.A.	0.207	0.215	0.008
2001	Lostwood W.A.	0.207	0.215	0.008
2002	Lostwood W.A.	0.165	0.178	0.013
Average	Lostwood W.A.	0.193	0.203	0.010
Overall Average		0.142	0.149	0.007

Coal Creek Station Unit 1 or 2 Delta Deciview 98th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SOFA/LNB Option 2 21% Reduction	Difference
2000	TRNP-SU	0.467	0.494	0.027
2001	TRNP-SU	0.482	0.509	0.027
2002	TRNP-SU	1.140	1.181	0.041
Average	TRNP-SU	0.696	0.728	0.032
2000	TRNP-NU	0.416	0.446	0.030
2001	TRNP-NU	0.512	0.547	0.035
2002	TRNP-NU	0.918	0.987	0.069
Average	TRNP-NU	0.615	0.660	0.045
2000	Elkhorn Ranch	0.300	0.314	0.014
2001	Elkhorn Ranch	0.473	0.505	0.032
2002	Elkhorn Ranch	0.746	0.789	0.043
Average	Elkhorn Ranch	0.506	0.536	0.030
2000	Lostwood W.A.	0.469	0.499	0.030
2001	Lostwood W.A.	0.469	0.499	0.030
2002	Lostwood W.A.	0.783	0.832	0.049
Average	Lostwood W.A.	0.574	0.610	0.036
Overall Average		0.598	0.634	0.036

Step 6: Select BART

The units have existing low NO_x burners and SOFA for removing nitrogen oxides and the plant is expected to have a remaining useful life of at least 20 years. The Department considers the incremental cost of the top three options to be excessive. If fly ash sales are not lost due to the use of SNCR, the cost for this alternative is not considered excessive. However, the maximum improvement in visibility for SNCR versus SOFA/LNB Option 1 is 0.105 deciviews based on the 98th percentile (0.027 deciviews based on the 90th percentile). The Department has found that the single source BART modeling overpredicts the amount of visibility improvement by a factor of 5-7 (see Section 7.4.2 of SIP). The Department considers the amount of visibility improvement from the use of SCNR versus SOFA/LNB Option 1 to be inconsequential. Because of the potential for lost sales of fly ash, the negative environmental effects of having to dispose of the fly ash instead of recycling it into concrete, and the very small amount of visibility improvement from the use of SNCR, this option is rejected as BART. The Department proposes that BART is represented by modified and additional SOFA plus LNB (Option 1). GRE has indicated the feasibility of, and the manufacturer has guaranteed, an emission limit of 0.15 $lb/10^6$ Btu on an annual average basis. An achievable thirty-day rolling average emission rate is expected to be slightly higher at 0.17 $lb/10^6$ Btu. The Department proposes that BART is 0.17 $lb/10^6$ Btu on a 30-day rolling average basis. Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

IV. BART Evaluation for Auxiliary Boilers No. 91 and No. 92

Auxiliary boilers No. 91 and No. 92 are distillate and residual oil-fired boilers with a nominal rating of 172 x 10^6 Btu/hr. The auxiliary boilers are only used when both units at the Coal Creek Station are down. During the baseline period (2000-2004), the auxiliary boilers were operated an average of 11.2 hours per unit per year. The annual average emissions per unit for this period were:

NO_x	0.09 tons
SO_2	0.19 tons
PM	0.08 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls and the currently permitted fuel limitation of distillate oil, residual oil or any combination of the two.

V. BART Evaluation of Emergency Generator

The emergency generator is driven by a 3,500 horsepower diesel engine. The generator is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated an average of 94.9 hours per year and the average annual emissions were:

PM	0.07 tons
NO_x	2.87 tons
SO_2	0.31 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VI. BART Evaluation for Emergency Fire Pump

The emergency fire pump is driven by a 200 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated an average of 14.0 hours per year and the actual annual emissions were:

PM	0.01 tons
NO_x	0.11 tons
SO_2	0.01 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at Coal Creek Station that emit to the atmosphere are as follows:

EU – Description	**Existing Control Equipment**	**Current PM Emission Limit (lb/hr)**	**Baseline PM Emissions (tons/yr)**
EU 7 - Lignite transfer house	Bagfilter	3	0.07
EU 8 - Lignite emergency reclaim system	Bagfilter	3	0.00
EU 9 - Lignite yard storage silos	Bagfilter	3	0.03
EU 10 - Lignite yard storage silos	Bagfilter	3	0.03
EU 11 - Crusher building	Bagfilter	3	0.07
EU 12 - Generation building coal hopper	Bagfilter	3	0.07
EU 13 - Falkirk mining Company mine silo base	Bagfilter	3	0.07

EU – Description	Existing Control Equipment	Current PM Emission Limit (lb/hr)	Baseline PM Emissions (tons/yr)
EU 14 - Generation building coal hopper	Bagfilter	3	0.02
EU 15 - Generation building coal hopper	Bagfilter	3	0.02
EU 16 - Generation building coal hopper	Bagfilter	3	0.02
EU 17 - Generation building coal hopper	Bagfilter	3	0.02
EU 19 - Scrubber building flyash silo	Bagfilter	3	0.02
EU 20 - Truck air slide flyash silo	Bagfilter	3	0.05
EU 21 - Truck air slide flyash silo	Bagfilter	3	0.05
EU 22 - Water treatment building	Bagfilter	3	0.03
EU 23 - Scrubber building lime handling system	Bagfilter	3	0.02
EU 24 - Scrubber building lime handling system	Bagfilter	3	0.02
EU 25 - Flyash railroad marketing silo	Bagfilter	3	0.05
EU 26 - Flyash dome	Bagfilter	0.4 (EP 26a-26b), 0.09 (EP 26e)	0.02
EU 27 - Coal Dryer	Bagfilter	3.1	0.3*
FS 1 - Cooling towers No. 91, No. 92, and No. 93	Fugitive	--	0.02
FS 2 - Boombelt conveyor (stackout)	Fugitive	--	0.02
FS 3 - Conveyor 909 (stackout)	Fugitive	--	0.04
FS 4 - Scrubber building flyash silo (stackout)	Fugitive	--	0.04
FS 5 - Coal pile maintenance	Fugitive	--	3.77

* Department estimate based on 2005 emissions

Based on the small quantity emissions from those sources (EU 7-27) that are controlled by bagfilters, which are considered the most efficient control devices, it is apparent that no additional control equipment will be cost effective. Materials handling units (FS 1-5) are uncontrolled sources of fugitive emissions. Based on the small quantity of emissions from those sources, it is apparent that no additional control equipment will be cost effective. Any additional controls would have a neglible effect on visibility impairment. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limits for the units is BART.

VIII. Summary

Source Unit	**Proposed BART Limit/Work Practice**				**Emissions Reduction (tons/yr)**		
	PM	**SO_2**	**NO_x**	**Units**	**PM**	**SO_2**	**NO_x**
Unit 1 Boiler	0.07	0.15 (30-dra) or 94% reduction	0.17 (30-dra)	lb/10^6 Btu	0	19,990*	1,607
Unit 2 Boiler	0.07	0.15 (30-dra) or 94% reduction	0.17 (30-dra)	lb/10^6 Btu	0	19,990*	1,607
Auxiliary Boiler No. 91	Continue current practices			N/A	0	0	0
Auxiliary Boiler No. 92	Continue current practices			N/A	0	0	0
Emerg. Gen.	Continue current practices			N/A	0	0	0
Fire Pump	Continue current practices			N/A	0	0	0
Material Handling EU 7-25	3	---	---	lb/hr	0	---	---
Flyash Dome EU 26	0.4 (EP 26a-26b), 0.09 (EP 26e)	---	---	lb/hr	0	---	---

Source Unit	Proposed BART Limit/Work Practice				Emissions Reduction (tons/yr)		
	PM	**SO_2**	**NO_x**	**Units**	**PM**	**SO_2**	**NO_x**
Coal Dryer EU 27	3.1	---	---	---	0	---	---
Fugitive FS 1-5	---	---	---	---	0	---	---
Total:						39,980*	3,214

* Reductions from 2000-2004 average emission rate adjusted for future fuel (dried lignite).

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate loading to the scrubber shall be accomplished by either:

    a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

    b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. The owner/operator will be allowed to average emissions (bubble) for SO_2 and/or NO_x for the two units using the following formulas:

$$\text{Average AER} = \frac{[(AER_1)(HI_1)+(AER_2)(HI_2)]}{(HI_1 + HI_2)}$$

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER	=	Allowable Emission Rate (lb/MMBtu or % Reduction)
ER_1	=	Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 1
ER_2	=	Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 2
HI_1	=	Actual Heat Input (MMBtu) of Unit 1
HI_2	=	Actual Heat Input (MMBtu) of Unit 2

Notes: ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average is determined in accordance with 40 CFR 60, Subpart Da, for the 30 successive boiler operating days (must be on a consistent basis of lb/MMBtu or % reduction).

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

References

1. K-fuels® website, 2007. www.evgenergy.com

2. EPA, 1995. Compilation of Air Pollutant Emission Factors Volume 1: Stationary Point and Area Sources. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711

3. Great River Energy, 2007. Coal Creek Station Units 1 and 2 BART Analysis; Revised December 12, 2007.

4. Bittner, James D.; Gasiorowski, Stephen A.; Hrach, Frank J.; Fly Ash Separation and Ammonia Removal at Tampa Electric Big Bend. Separation Technologies, LLC, Needham, MA 02492.